OASIS
LANDSCAPE
ARCHITECTURE
AND PLANNING

23 March 2010

Messrs. John Peirson and John McKenzie
MRS & County of San Luis Obispo Planning & Building Department

Via overnight delivery & courier

RE: EXCELARON PROJECT EIR (DRC 2009-00002) – INFORMATION REQUEST #1

Gentlemen,

We have reviewed Information Request No. 1 and are pleased to submit the following responses. Please note that your questions are noted in blue, while our responses are provided in black. We would appreciate an opportunity to discuss our responses with you at your earliest convenience. Thank you in advance for your consideration. We anticipate that this information will now allow you to finalize the draft Project Description.

A. Drilling/Redrilling/Workover

1. Please provide information on the drill rig that may be used for the project. The application talks about a Kenai rig. Kenai has approximately 14 different rigs that may be available with different specifications. Ideally, we would like to know the Kenai rig # that could be used. In particular, we are looking for the following information.

a. Drilling range (feet with what size drill pipe),
b. Drawworks (motor sizes, type, and CARB certified emission factors),
c. Mud Pumps (motor sizes, type, and CARB certified emission factors),
d. Generators (motor sizes, type, and CARB certified emission factors),
e. Mast (height-free standing and rating),
f. BOPE (type, accumulator capacity),
g. Water/Fuel Storage, and
h. Layout of the rig.

Please see the attached Kenai Rig #4 Specification, Layout, and Emissions sheets. The Specification and Emissions sheets address items a. – g., while item h. is addressed on the Layout sheet. We anticipate that the Kenai Rig #4 represents the maximum sized rig that may be required for the proposed project.

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2. Please provide an estimate of the total vertical depth (TVD) and total measured depth (TMD) for each of the wells that will be drilled. (If this information is not available, then provide the range of TVD and TMD that are likely for the 12 well scenario.)

The Exploration/Testing phase will begin with a "well pilot program" (WPP) designed specifically to gather data on the underlying geology and oil reserves. The WPP includes the drilling, testing, and analysis of the first four (4) production wells. The first well of the WPP will be drilled to a total vertical depth (TVD) of approximately 3000 feet. Core samples will be taken with an analysis of fluids, lithological characteristics, saturations, fracture density, and fracture aperture sizes. Fracture imaging logs will also be completed in the bore hole to ascertain fracture density and orientation. Additionally, some small scale, lab-run hot water flooding tests will be completed on the core samples.

These analyses in conjunction with some initial testing production data will be input into a fractured reservoir computer simulation model. A computer simulation is required to understand potential production interval widths (i.e., "pay zone"), injection rates, injection pressure, production rates, hot water soaking time, production time, sweep efficiencies, recovery factors and inter-well distances. Only after the computer simulation is completed and analyzed will the next two or three wells be drilled.

The WPP wells will be produced for a period of time and all data, including additional core and logging data, will be added to the computer simulation model. Once the WPP has been modeled, the exact TVD of the remaining wells can be calculated. However, it is estimated that the TVD of the remaining production wells will be between 1500' to 3000'. A disposal well will not be drilled until completion of the wells in the WPP.

Total measured depth (TMD) is more difficult to ascertain. Ideally, for economic reasons, the remaining production wells will be vertical wells, however, data from the pilot program and subsequent computer simulation may suggest that inclined well paths will create more efficient production. Conversely, inclined wells from the same surface location may lessen any perceived environmental impact but could be economically unfeasible. It is estimated that the TMD will be within 10% ±, not to exceed 20% of TVD.

3. Please provide a list and estimated quantity of chemicals that may be used for the drilling of each well. This should include any chemicals that will be used as part of well completion operations.

No chemicals are proposed for use during drilling.

4. Please provide the following information on the muds and cuttings.
a. Provide an estimated mud composition (see example at the end of the document)?
b. Will any oil based muds be used?
c. An estimate of the quantity of muds and cutting that will be generated for each well.
d. Will the muds and cutting be placed in bins or will mud pits be used?
e. If mud pits will be used provide estimated dimensions for each pit.
f. How will the muds and cutting be disposed of during drilling?
g. If the cutting will be trucked offsite, where will they be taken?

The proposed mud composition will be a mixture of bentonite clay and water. No oil based muds will be used. Approximately 160 bbls of mud will be required to drill a 3,000 foot deep well. The mud will have additives such as bi-carbonate, soda ash and polymer, all of which are listed as approved, non-hazardous additives by the California Dept. of Health Services. The rock cuttings volume from drilling the upper part of the hole to 350 feet prior to setting the 7 ⅝" casing is 185 cubic feet. The rock cuttings from drilling the remainder of the open hole to 3000 ft. is 675 cubic feet. Total cuttings volume = 860± cubic feet or 32 cubic yards of material. All muds and cuttings will be placed into bins. Cuttings will be dried and used onsite for containment berms. All muds will be hauled offsite to an appropriate nonhazardous disposal facility.

5. Please provide more information on the estimated wellbore configuration for each well (see the attached figure an example of the information we would like).

See the attached well configuration diagram and time estimate for drilling.

6. Please provide an estimate of the number of well workovers that would be expected to occur each year.

A conservative estimate would be one (1) work over per well per year. A workover would last one day or approximately ten (10) hours.

7. If well workovers are planned, please provide a description of the well workover rig along with engine types, hp, and emission factors.

A typical workover rig for a 3000 foot well includes:

- A 94 foot mast;
- A 75 foot truck length;

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- A 300 HP diesel rig engine with new low emissions engine mandated and approved by CA Air Resources Board; and
- Fuel use of approximately 1.5 gallons/hour.

8. Please provide an estimate of the number of redrilling that would be expected to occur each year. (The EIR will assume that the same drill rig used for the initial well will be used for well redrills unless detailed specifications are provided for a redrilling rig.)

Ideally, no redrills would be required. However, a conservative estimate would be one (1) redrill per well every five (5) years.

B. **Reservoir (Oil/Water/Produced Gas)**

9. Please provide additional information on the estimated water production level over the life of the project. The application has used a number of different values for water cut. We would like to get an estimate of the water cut per year of production. Would the maximum water cut over the life of the project be 80%, or after 5 years (years 6-10, etc), would/could the water cut increase to 85%, 90%, 95%? The Engineering Report only addresses water cut out to the first five years (80% after five years).

See the attached report by Dr. Arthur Halleran regarding estimated water cuts in a fractured Monterey reservoir.

10. Please provide a geological cross section for the site that shows the depths of the various formations and which formations are proposed for possible development as part of the project. (See the attached example).

See attached cross sections. The geological formations proposed for possible development are outlined in the Supplement to the Application Section 2.4.3, page 8.

11. Please provide an estimated produced gas composition including any H_2S.

See the Golder Air Quality Impact Analysis Table 5a for estimated produced gas composition. This composition estimation was based gas production from a similar reservoir in Kern County. Attached is a sample annual gas reading from the Barham Ranch field discussed in Dr. Halleran's report. Historical Huasna field drilling documents make little mention of encountered H_2S and any produced gas will be handled as described in Supplement to the Application Section 2.4.6.5, page 13 and outlined in the Cannon Facility Engineering Report page 8 and process flow diagrams.

C. Engineering/Design

12. Based upon the Engineering drawings it looks like under the four well scenario (test and exploration phase), one well will be drilled at the shipping site, one well at pad #1 and two wells at pad #2. Please confirm these numbers. Will each of these pad locations have baker tanks and temporary equipment, including loading facilities, propane, etc? Or would the pipelines to the shipping site be installed?

The drawings submitted as part of the Engineering Report were prepared for graphical purposes only. The exact surface location of each producing well will not be known until such time as more reservoir data has been gathered. However, all twelve (12) wells will be located within one of the three (3) existing defined well pads. The three existing pads were chosen because they are geologically situated to effectively analyze the reservoir, as well as eliminate potential environmental impacts and provide some flexibility in surface location.

The surface location of the WPP wells can be estimated, however the subsequent well locations will be dependent on the results of the computer simulations previously discussed. The current drawings depict a four well scenario with one (1) well to be drilled at the shipping site, one (1) well at pad 1 and two (2) wells at pad 2. The following describes the location of the WPP wells:

- The first well will be drilled on well pad 2. Based on the results of the first computer simulation up to two (2) more wells may be drilled on pad 2. The exact inter-well spacing will be based on the data from the first well and the results of the computer simulation. The estimated inter-well spacing may be 150 feet. Consolidation of all the WPP wells on a single pad will reduce any geological risk (i.e., most of the geological control is on and adjacent to well pad 2), thereby reducing the surface footprint for drilling, tanks, etc. during the Exploration/Testing phase.
- The fourth well will be located based upon results obtained from the first three (3) WPP wells.
- If water disposal is required for the Exploration/Testing phase, the disposal well will be drilled at the shipping site.

13. Based upon the engineering drawings it looks like under the twelve well scenario two well will be drilled at the shipping site (one production and one disposal), five well at pad

#1 and six wells at pad #2. This is a total of 13 wells drilled. Please confirm these numbers.

The drawings submitted as part of the Engineering Report were prepared for graphical purposes only. The exact surface location of each producing well will not be known until such time as more reservoir data has been gathered. However, all twelve (12) wells will be located within one of the three defined well pads. The three existing pads were chosen because they are geologically situated to effectively analyze the reservoir, as well as eliminate potential environmental impacts and provide some flexibility in surface location.

The Cannon Engineering Report depicts the twelve (12) well scenario with two (2) wells at the shipping site (one production and one disposal), five (5) wells at well pad 1 and six (6) wells at well pad 2. This is a total of thirteen (13) wells, twelve production wells and one disposal. For analytical purposes please consider the following surface location scenario.

- Well pad 2 may accommodate the initial three (3) WPP wells and two (2) additional production wells. The latter two wells may be inclined wells bringing the total to five (5) production wells at well pad 2. To reiterate, the exact quantity of producing wells at this location will be dependent on the results of the computer simulations.
- Two (2) wells may be inclined in order to assist with the evaluation of the hot water flood production characteristics of inclined wells for this pool. Additionally, this location will have already provided production data results from the WPP and therefore efficiency comparisons can be made between inclined and vertical wells.
- With satisfactory results from the WPP wells located on well pad 2, a single vertical well may be drilled at well pad 1. If economically viable oil accumulations are discovered, two (2) additional vertical wells may be drilled on this pad. If computer simulations and production results from the inclined wells on well pad 2 are satisfactory, a single inclined well may be drilled on well pad 1 for a total of four (4) production wells at this location.
- If drilling of the water disposal well at the shipping site provides information related to economic accumulations of oil, three (3) vertical wells may be drilled at this location. Conversely, if economic accumulations of oil are not found, then the three wells will not be drilled at this location.

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The total wells to be drilled include twelve (12) production wells and one (1) water disposal well.

14. The Engineering Report estimates a gross fluid production of 240 barrels per day per well. This report also shows that estimated water cut for each well could increase to 80% by year five of production (Figure 1). Table 1 shows that for the 12 well case the peak waste water disposal rate would be 1,128 barrels per day, which has been used as the design basis for the disposal well pumps. However, this is based upon the water production rate in year five, which is only 66%. In year 10 the water cut would be 80% based upon the data in the Engineering Report. This would equate to a water disposal rate of 1,920 barrels per day assuming 10 well are producing on a given day, and 480 barrels of produced water is used for hot water injection into a total of two wells. Why has the water disposal system not been designed for this higher water rate at the later years of production?

See responses to questions 9 (above) and 15 (below).

The maximum fluid throughput for the facilities design is limited by the proposed pipeline and tank sizes. Regardless of the water cut percentage, the total amount of fluid that can be processed in a twenty-four hour operating period equals approximately 2,400 BGPD. If the water cut is exceedingly higher than expected, less oil will be produced on a daily basis. Conversely, if the water cut is lower than expected, wells may need to be produced at a lower then optimal rate. Additionally, the project is confined by daily oil transport truck trips, a maximum of six (6), which serves to limit the daily production amounts that can be handled by the facilities.

15. Please provide an updated Table 1 in the Engineering Report that shows the maximum facility production levels by year from year 1 through year 10.

See attached revised Table 1. This table was prepared utilizing information prepared by Dr. Arthur Halleran.

16. The Engineering Report uses a well depth of 1,500 feet for the design of the hot water injection pumps. However, the Application Supplement states that hot water flooding is viable to a depth of 2,000 feet. Based upon the data in hydrology report is appears that the Monterey formation exceeds the 2,000 foot depth. Therefore, why was the injection pump design not set at 2,000 feet?

The estimated net pay zone for the Monterey formation in the Huasna Valley is derived from data from previously drilled wells (i.e., the LaVoie-Hadley wells located on well pad 2) and is assumed to be approximately 2400 feet thick. However, the exact thickness of the net pay zone at well pad 1, the shipping site or over the majority of the prospect is not known and could be anywhere from 0 feet to 1000's of feet thick. The placement of the pump for each and every production well is also unknown at this time. For any given production well, the lower most 200 to 300 feet of pay zone will be left uncompleted to avoid the encouragement of water encroachment during production. The true range will be defined by the data acquired during the WPP. The production wells may be produced at different intervals over the course of their lifetimes with the pump being moved accordingly each time. The pump was assumed to be located at 1500 feet as it represents an average producing depth.

17. Please provide a complete list of equipment that would be needed at each well pad in the test and exploration phase. The Supplement to the Application only states, "Temporary facilities (i.e., portable "Baker" tanks, propane-driven generator, well pumps), but the information hold response 9-29-09 states that hot water flooding will be used during the test and exploration phase, and the Air Report lists a number of propane burning stationary sources. Please provide PFDs and plot plans for each well pad and shipping site for the test and exploration phase. (This equipment is not shown in the Engineering Report for the four well scenario).

See attached list of temporary, portable facilities. The process flow diagram for the Exploration/Testing phase is similar to the proposed permanent facilities, except for the fact that these are temporary in nature and may be smaller in scale. The site plans are the same as provided with the exception of production well locations discussed in question 12. See the Cannon Engineering Report for PFD's and site plans.

Several calculations and sizing sheets have been updated to reflect the temporary facilities. The following information supplements the updated calculations. All tanks (excluding propane storage) will be Baker tanks, with two standard sizes used (238 and 500 BBL).

<u>Wash Tanks</u>

- Maintained two (2) parallel tanks, with each handling half the total flow during normal operation (180 BOPD, 180 BWPD each).
- Each tank has a residence time of approximately sixteen (16) hours to promote oil-water separation.

Stock Tanks

- Maintain two (2) tanks for adequate oil storage (360 BOPD total).
- Oil rate into facility requires approximately fifteen 1(5) truck trips/week, or 2 – 3 trips/day depending on tank levels (Truck capacity assumed = 158 BBL).
- Tanks will normally operate between safe high- and low-levels. Should truck access to the site become unavailable, production can continue into the tanks for forty (40) hours from the last truck visit, before production has to shut down.

Water Tank

- Water tank was sized assuming the disposal well will not be necessary in the Exploration/Testing Phase.
- Water production is 360 BWBD, while water injection is 240 BWPD.
- Trucks will be required to remove excess oil from facility. Typical vacuum trucks (95 BBL capacity) were assumed. The facility water balance requires eight (8) vacuum truck trips/week to remove excess water. The Water Tank will normally operate between safe high- and low-levels, with adequate surge capacity.

Facility Heating and Electrical

- Heating loads and electrical requirements were all reduced in this phase, due to smaller tanks and less required pumps/pumping units/etc.
- Assumed heating requirements are for Wash Tanks, Stock Tanks, and Heat Exchanger for water injection
- Propane truck (1,000 gal) trips have been reduced to three (3) trips/week.

Piping and Conduit

- With all wells and processing equipment at one location, the amount of piping and conduit required has been reduced.
- Should the 4th well be drilled elsewhere, additional piping and conduit will be required.
- Values listed as xxx / yyy. Values xxx refer to distances required if all wells are drilled at Well Pad #2. Values yyy refer to distances required if 4th well is drilled elsewhere.
- This also applies to fire suppression system requirements.

18. Will the project require the use of blend oil or diluents for mixing with the produced oil prior to truck loading? The PFDs show blend oil unloading and storage (T-120 and T-125). It appears that one blend oil tank is located at well pad #1 and well pad #2. What is the purpose of these blend oil tanks? (There purpose does not seem to be discussed in the Engineering report.) If blend oil is required please provide the following information.
a. How much blend oil will be needed per barrel of produced oil?

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b. Where will the blend oil be obtained?
c. What is the estimated composition of the blend oil?
d. How many truck trips per day will be needed to deliver blend oil to the site?

During long-term operations, a minimal amount of high gravity crude oil (20-30° API) will be blended with the native crude production to lower the viscosity and raise the gravity. The blending will take place within the flowlines (pipelines) as produced fluids are transported to the processing facilities and not downhole. The resultant increase in gravity is typically required by the crude buyer to render off loading and crude handling easier and more efficient. It is anticipated, based on historical use of blend oil in some Santa Maria heavy oil fields, 20 barrels or less per day of the lighter gravity oil will be required. This would result in the potential of 600 barrels of blend oil per month or approximately 5 truckloads. This oil will be transported to the project as a truck "backhaul' (i.e., a tanker truck coming into the project site to haul "out" produced oil will haul "in" a load of blend oil) resulting in no additional truck trips. It is unknown at this time where the blend oil will be obtained, but we anticipate a local source.

19. Would a flare be used during normal operations in future field development phase? If not, how will upset and gas facility maintenance activities be handled?

No flaring is proposed for long-term operations. Any produced gas will be handled as described in Supplement to the Application Section 2.4.6.5, page 13 and outlined in the Cannon Facility Engineering Report page 8 and process flow diagrams.

20. During the exploratory and testing phase, what will be done with the gas? Would a gas flare be installed at each of the 3 sites for combustion of the gas?

After drilling is completed for the initial three (3) wells a one to two day test production run will provide data on reservoir pressure, temperature, fluid properties and flow characteristics of the reservoir. For safety purposes, a flare stack will be in place to handle any encountered gas. However, based on historical drilling records and known attributes of similar fields, the likelihood of encountering significant gas is assumed to be remote. After the initial one to two day test period, temporary facilities will be constructed to handle gas as described in the Cannon Facilities Engineering Report and a flare stack will not be needed.

21. Please provide the reasoning for the well spacing provided in the Engineering Report. The well spacing appears to vary between approximately 30 and 50 feet. What is the

minimum well spacing that is needed to allow for access for well maintenance and well workover/redrill activities?

The well spacing of the initial three wells may be up to 150 feet in order to obtain data over a larger area. Hot water flooding has shown to have an effective radius of up to 150 feet from the well bore. This effective radius would suggest that the wells could be placed 300 feet apart. This spacing, due to the expected thick net pay zones of the Monterey, may require a substantial amount of time to effectively hot water flood the well. A 150-foot inter-well distance would provide a 75-foot radius around each borehole and may ultimately allow for more efficient oil production for the total thick net pay zone.

The exact inter-well distance for any wells beyond the initial WPP will be determined from the geological data gathered during testing and from the computer simulations. Modern drilling technologies allow wells to be spaced at 15 feet apart, however this may not represent the most effective spacing for production at the Huasna field.

22. Please verify that the water injection and disposal pressures will be 200 psig at the well head (well head pressure). This seems like a very low pressure. What is the estimated reservoir pressure and temperature at the production intervals?

It is important to note that the DOGGR dictates and monitors maximum injection pressure for a field. The injection pressure will be evaluated based upon the data gathered from the WPP wells and subsequent production testing. Employing the correct injection pressure is critical within a fractured reservoir (i.e., the pressure must be high enough to allow injection of enough hot water to economically produce the oil while preventing early water breakthrough in nearby producing wells).

The injection rate for the water disposal well will be dependent on the depth of the zone used for disposing. A range of 200-800 psig can safely be used for estimating purposes.

23. The Engineering Report states that each well will be subject to hot water flooding for one day and then produce for three to five days (page 4). It is also assumed that about 240 barrels of hot water will be injected in a well each day during hot water flooding, and up to two wells would be on hot water flooding at any one time. Under the twelve well scenario with two wells on hot water flooding for one day, the cycle time through all 12 wells would be six days. This means that each well would produce for five days and have one day of hot water flooding. For a three day production/ one day hot water flood case, three wells would have to be under hot water flood at any time, which would increase the required hot water flood pumping requirements from 480 barrels per day to 720 barrels per day. It does not appear that the design capacity of the hot water injection pumps

represents the highest value based upon the discussion sited above in the Engineering Report. Please explain why the three day production case was not used as the design basis for the hot water injection pumps. It would seem that the three day production case would represent the maximum case for the design of these pumps, and would provide the operator with more flexibility in terms of oil field operations.

The optimal production to water flood ratio is unknown at this time and will be better understood after the WPP and computer simulations are completed. It is Excelaron's intent to operate in a manner that is both productively efficient and economic. Additionally, the project is constrained by the quantity of produced oil that can be transported offsite daily (i.e., 840 BOPD). Despite the facility's ability to operate at higher levels, it may be required to operate at less than optimal conditions which will affect the production to water flood ratio.

Operating at a 3 to 1 production to water flood ratio may represent the maximum case for design, but inadvertently result in an uneconomical operation and an unacceptable fluid production level (i.e., beyond the maximum daily oil production levels to maintain the daily transport at 840 BPOD). A more accurate optimal production to water flood ratio can be determined only after reservoir and production data has been gathered and analyzed.

24. Please provide grading plans for the well pads and shipping site for both the Testing and Exploration Phase and the Production Phase. The Air Report shows grading activities in both of these Phases for the well pad and shipping site (Tables 2 and 6a). For the Testing and Exploratory Phase the Air Report states, "In addition to the road improvements, the existing well pads will be cleared and improved. Approximately 72,000 cubic yards of material will be moved during this two week period." However, it is not clear how much of the well pads and shipping site will be graded and developed as part of the Testing and Exploratory Phase, and how much will be developed in the Production Phase. The Application Supplement discusses grading/cut/fill for the Testing and Exploration Phase (page 26), but there is no discussion of the grading impacts for the Production Phase, yet the Air Quality report has emissions for these activities. We have not been able to find a discussion of the amount of grading/cut/fill for the Production Phase. Will the well pads and shipping site be completely grading and constructed as part of the Testing and Exploratory Phase?

All pads and roads will be graded as part of the Exploration/Testing phase in order to make the site accessible for construction vehicles. Additionally, the road will be graveled, paved in sections, and have dust suppressant applied. Estimates for cut/fill and preliminary grading plans have been provided. See Mankins Road disturbance graphics. Additionally, as part of the DOGGR plugging and abandonment program, the road and pads have been graded and repaired in some sections. This may lessen the estimated amount of cut/fill proposed. Some additional earthwork may occur during the Production phase for spill containment purposes and to accommodate proper drainage. This has been accounted for in the Air Quality report.

D. Other Items

25. Will the Firewater tanks and hydrants be installed and placed into service prior to the test and exploration phase?

Firewater tanks and hydrants will be installed prior to the Exploration/Testing phase. Additionally each drilling rig is equipped with fire safety and prevention equipment.

26. Will the disposal well be drilled and used in the test and exploration phase? If not, would any excess produced water have to be transported offsite by trucks? If water is trucked offsite, provide an estimate of the volume of water that would need to be trucked offsite per day.

After the well pilot program and computer simulations are completed, produced water volumes and related operational measures will dictate the timing and location of the water disposal well. If the Exploration/Testing phase produces more water than can be used for hot water flooding, a disposal well will be drilled at that time. In the interim, excess water will be hauled offsite. Truck trips related to that activity have been accounted for in the Orosz Engineering Traffic Analysis -Enclosure D.

27. Please provide additional information on Phase III: estimated amount of materials to be cleaned up, hauled away, number of truck trips, etc.

See attached list of materials currently onsite to be removed during Phase III. Truck trips related to this activity have been accounted for in the Orosz Engineering Traffic Analysis - Enclosure E.

28. Please provide a list and estimated quantities of chemicals that are expected to be used on site for the future development phase.

See response to question 3 (above).

29. Would the engines and generator be designed for a combined use of propane and produced gas? If so, please provide additional information on engines/generators capable of operating on a variable mixture of propane and natural gas.

All produced gas will be routed to the Vapor Recovery Unit (VRU). Pipelines will transport all gas from their sources to the VRU where the gas will be scrubbed, compressed, and used as fuel for the heater/burners. The produced gas will not be used in engines or generators. See Cannon Facility Engineering Report page 8 and PFDs.

30. Please provide a copy of the Williamson Act Contract for all project parcels that are under the Williamson Act.

See the attached Williamson Act contract for parcel 085-271-001 and correspondence from Cannon confirming that the shipping site is not located within contracted property.

31. Please provide example photos of a natural gas or propane driven well pump.

The well pump is driven by a 10 hp propane driven combustion engine. The well pump itself is not powered by propane. A cut sheet for a typical industrial engine that can be run on propane is attached. These engines are used in agriculture, industrial, and gen-set applications, and would be well suited to run pumping units and generators on-site. (NOTE: this particular unit is larger than required for the pumping units) See attached engine cut sheet and pumping unit photo.

32. Please provide the estimated dimensions of the well pumps.

Please see the attached pumping unit cut sheet and Cannon Facilities Engineering Report Appendix A.

33. Please provide a preliminary drainage plan for the well sites, shipping site, and the road used for access to the sites.

Estimates for cut/fill and preliminary grading plans have been provided. See Mankins Road disturbance graphics. See response to question 34 for a response to drainage.

34. Please provide a preliminary Storm Water Pollution Prevention Plan (SWPPP) for the well pads and shipping site that covers the operational phases (testing/exploration and future field development).

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See the attached narrative describing storm water best management practices.

END OF RESPONSES

Thank you in advance for your consideration of our responses to your comments and questions. Please contact us should you need clarification of any of these items.

Respectfully,
OASIS ASSOCIATES, INC.

C.M. Florence, AICP Agent
EXCELARON LLC

Attachments

c: G. Jagelman
K. Matlick
A. Halleran
08-0112